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THE CRUDE OIL MARKET: PRICING AND ITS IMPLICATIONS

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The Crude Oil Market:
Pricing and its Implications

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Abbreviations

API	American Petroleum Institute | Refers to the API measurement of relative density
bpd	Barrels Per Day
BFOE	The Brent Blend, Forties, Oseberg and Ekofisk crude oils | The physical basis of the Brent Market
Brent	Commonly refers to a basket of North Sea crudes (BFOE) as opposed to the specific Brent field in the East Shetland basin of the UK
Brent Blend	Crude oil from the Brent field combined with the Ninian field
CADS	Cash Flow Available for the Project's Debt Service
CIF	Cost Insurance and Freight
EIA	The US's Energy Information Agency
FID	Final Investment Decision
FOB	Free On Board
IEA	International Energy Agency
IRR	Internal Rate of Return
IOC	International Oil Company
OECD	Organisation for Economic Co-operation and Development
OIES	Oxford Institute for Energy Studies
OPEC	Organisation of the Petroleum Exporting Countries
OPEC Plus (+)	An alliance between OPEC and a few non-OPEC countries, such as Russia and Mexico, that serves to facilitate balance in the crude oil market
OPEX	Operating Expenditure
PRA	Price Reporting Agency
PV	Photovoltaics
WEO	World Energy Outlook
WTI	West Texas Intermediate

Contents

How is Crude Oil Priced? 5
The Brent Market 7
The WTI Market 8
The Brent and WTI Relationship 8
Where are the main demand and supply hubs for Crude Oil? 10
Box 1: Crude Quality and Refinery Demand 11
What are the determinants of Crude Oil Price? 12
How did we arrive at the current sub $50 crude oil price environment? 12
Short Term Outlook 19
Box 2: Oil Storage Capacity 20
The Takeaway 22
The Forecasting Disclaimer 22
How do IOCs react to a sub $50 price collapse? Emphasis on the offshore sector 24
How does a significantly lower crude price impact an IOC's project that has received the Final Investment Decision? 26
Box 3: Fiscal Breakeven 29
How will renewable energy projects be impacted by a prolonged oil price low? 30
Investment in Oil Supply and Power 30
Will a strong recovery of global demand and inadequate investment in Upstream Projects pave the road for price highs? 31
References 34
Appendix 37

How is Crude Oil Priced?

There are hundreds of varying crude oil qualities extracted from geographically diverse locations around the world. Under the current market-based pricing system, crude oil is priced per benchmark crudes.[1] Brent and WTI are the two most referenced price benchmarks. Crude oils are priced at a premium or discount to the most relevant benchmark after considering its physical characteristics, among other factors. The price of the benchmark crudes is assessed by Price Reporting Agencies, a foundational aspect of the oil industry. Platts and Argus are the two leading PRAs and their price assessments form the basis of billions in spot and futures transactions.

The physical characteristics of crude oil, as evidenced in an assay, are mainly its specific gravity, sulphur content, viscosity and pour point. The two characteristics that exert the most weight in pricing are the specific gravity and sulphur content measurements. Specific gravity is assessed using the American Petroleum Institute (API) measurement of relative density; a crude is classed along a heavy to light range based on its API. If a crude possesses less than or equal to 0.5% of sulphur, it is considered a sweet crude while crude with more than 0.5% is classed as sour. The combination of these two measurements give rise to the detailed classification of crude quality as "Light Sweet," "Light Sour," "Medium Sweet," "Medium Sour," "Heavy Sweet" and "Heavy Sour."[2]

Crude oil is subject to derived demand. It is the input sought after by refineries to produce a range of petroleum products. The quality of the crude input defines the refinery's yield. Heavier and sourer crudes require steeper capital investments for a refinery to transform the heavier hydrocarbons into lighter

[1] There are two primary pricing mechanisms. Buyers and sellers can operate under a fixed and flat price where there is no reference to a price benchmark. A floating price mechanism linked to a benchmark is more common.

[2] Classification of crude oil varies. The OIES's classification is described above. Light crude oil per S&P Global Platts is equal to or above 34 APIº while the IEA uses above 32 APIº. The sour crude oil threshold is 1% for the IEA.

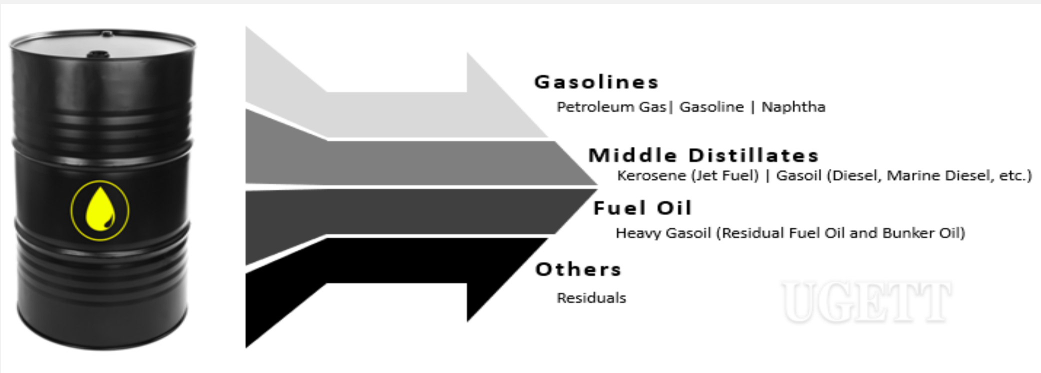
products and to reduce the sulphur content of its output. The market premium of light sweet crude over their heavy sour counterparts is rooted in the refineries' ability to maximise value from more marketable barrel cuts. Refined heavy sour crude produces greater low end-barrel cuts, heavy gasoil and residue output, in the absence of significant capital investments in coking and cracking as compared to the top-end and middle cuts such as gasoline, kerosene (jet fuel) and diesel distillates.

Table 1: Crude Oil Classification using OIES parameters

	Description		Classification					
	API		Equal to or greater than 35°	Equal to or greater than 35°	Equal to or greater than 26° and less than 35°	Equal to or greater than 26° and less than 35°	Less than 26°	Less than 26°
	Sulphur Content		Less than 0.5%	Equal to or greater than 0.5%	Less than 0.5%	Equal to or greater than 0.5%	Less than 0.5%	Equal to or greater than 0.5%
	Country	Crude	Light Sweet	Light Sour	Medium Sweet	Medium Sour	Heavy Sweet	Heavy Sour
South America	Argentina	Escalante					■	
	Brazil	Marlim						■
	Brazil	Roncador						■
	Columbia	Castilla Blend						■
	Columbia	Magdalena						■
	Columbia	Vasconia						■
	Ecuador	Napo						■
	Guyana	Liza				■		
	Peru	Loreto						■
	Venezuela	Mesa 30				■		
	Venezuela	Santa Barbara	■					
North America	USA	WTI (Cushing)	■					
	USA	Wyoming Sweet	■					
	USA	West Texas Sour				■		
North Sea	Norway	Ekofist	■					
	Norway	Oseberg	■					
	UK	Brent-Ninian	■					
	UK	Forties		■				
Africa	Ghana	Jubilee	■					
	Nigeria	Forcados			■			
	Nigeria	Bonny Light			■			
Middle East and CIS	Saudi Arabia	Arab Light				■		
	UAE	Dubai				■		
	Oman	Oman				■		
	Russia	Ursals				■		

Assay Data from S&P Global Platts

Diagram 1: Crude Oil Barrel Cuts



The Brent Market

The prices assessed from the Brent market are utilised directly or indirectly in circa three-quarters of the international trade in oil (Fattouh 2011). Brent is a North Sea crude. However, the physical basis of the market is a basket of North Sea crudes as opposed to its origin as the single light sweet crude of the Brent field in the East Shetland basin. The mid-1980s production of circa 885,000 bpd declined significantly over the 1990s to the 2000s and other North Sea crudes were added to the physical base to secure the benchmark (Fattouh 2011). The physical base of the Brent market includes the Brent Blend, Forties, Oseberg and Ekofisk (BFOE) crudes. The crudes have a specific gravity of 30º to 40º API and sulphur content of 0.2% to 0.1%. The Brent Blend has a 38.5º API and a sulphur content of 0.39%.

Brent has assumed its position as the prime benchmark in part to factors of marketability, competition and security of supply. The light sweet physical characteristics and location of Brent underscores its marketability and demand to both the US and European refineries. The robust political and legal system facilitates security of supply. Measures are taken to prevent limited competition market structures from forming as evidenced in Middle Eastern countries since this can result in price manipulation. The North Sea region represents ownership diversification, a key quality of an international benchmark.

The Brent Market is multi-layered due to the financialisation of the commodity market. The spot market, known as Dated Brent, is the physical basis on which the forward, futures, exchange for physical, options and other contracts are traded on. The standard cargo size in the Dated Brent Market is 600,000 barrels with a tolerance attached (Tamvakis, 2018). There are over 250 companies with ownership rights to North Sea crude, reflecting the diversified ownership referenced above, and there are less than 50 operators of the crude fields. Equity holders of a BFOE crude nominate two months ahead for the upliftment of crude at the respective terminal (Tamvakis 2018). A loading programme is then structured well in advance of the delivery month. The delivery mechanism divides months into laydays, each three days long, when the nominated vessel will load. Brent is mainly physically traded with the UK, North West Europe and the US and faces competition from light sweet crudes of West Africa, heavier/sourer crudes of Saudi Arabia, Mexico and Venezuela, and from US domestic production, among others.

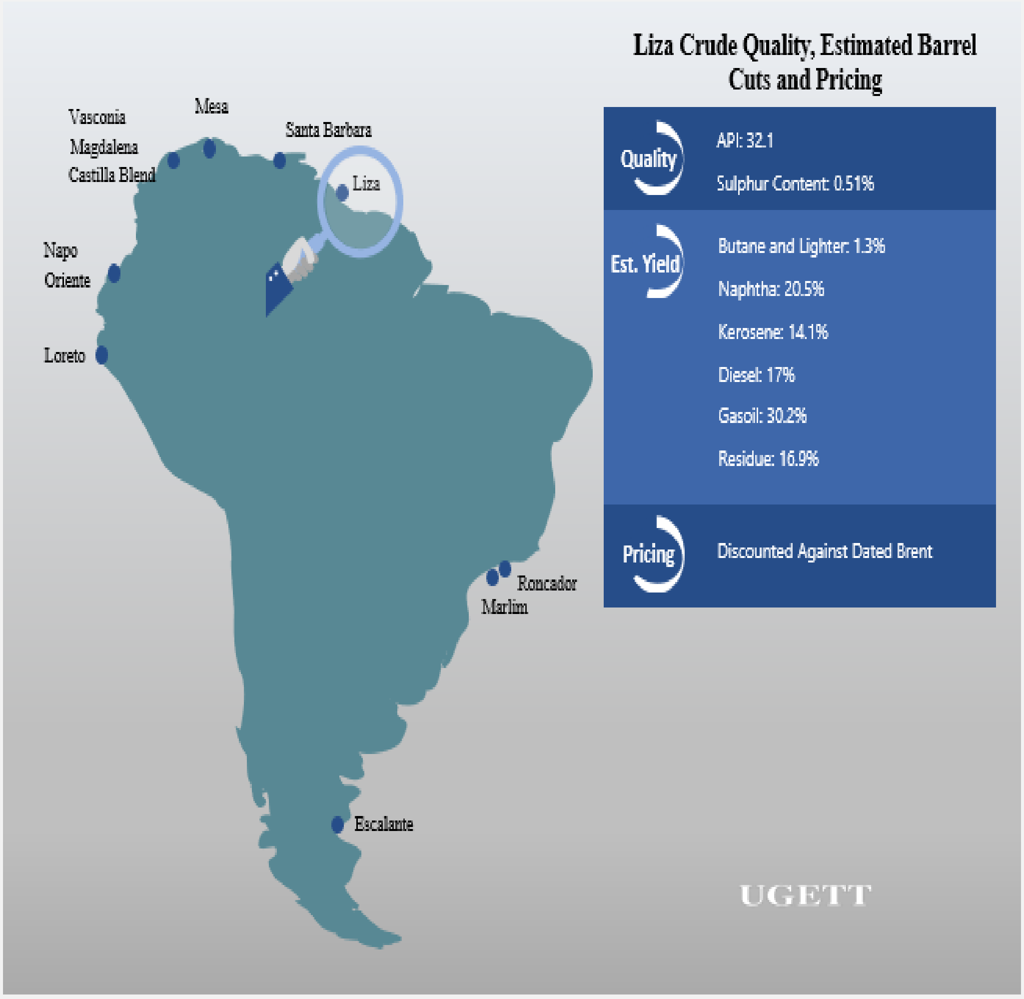
The WTI Market

The WTI benchmark is a crude oil blend, lighter and sweeter than Brent, from the US's West Texas Permian Basin. The crudes that form the blend are from fields in Texas, New Mexico, Oklahoma and Kansas. The WTI market is multi-layered with futures and other derivatives forming on the physical market trades. While the forward market existed before the introduction of the futures on the New York Mercantile Exchange in 1983, its need diminished as opposed to Brent's forward market that played a key role as a buffer due to declining liquidity (Miller et al. 2010). The physical basis fundamentally differs from other main benchmarks due to its landlocked and pipeline nature. WTI is priced at three different hubs; the Cushing, Oklahoma hub forms the basis of the benchmark assessment. Other crude oils produced in the United States and crude oil imported into the country from Canada, Central and South America, among others, are generally priced on the WTI benchmark.

The Brent and WTI Relationship

The price of Brent has historically been lower than the price of WTI due to the quality and location differential. While both crudes are priced FOB, Brent has competed in the US Gulf against WTI and thus priced less for the CIF value to be competitive (Tamvakis, 2007). Due to the rest of the world appeal of Brent outside the US, its pricing is generally more sensitive to Middle Eastern tensions, demand developments in China, among others, while WTI is more sensitive to the Americas. However, the rule of thumb is that Brent and WTI prices move in the same direction. The WTI benchmark displays many of the attributes that explains Brent's prime status, but its pipeline nature makes it vulnerable to bottlenecks that can skew its price from other crude prices. In the first half of the past decade, there was a significant divergence between the two main benchmarks fueled by the US shale revolution and WTI transportation bottlenecks. WTI began trading at a discount to Brent in contrast to its pre-2011 norm. The usually low single-digit negative spread peaked close to $30 and has set a positive trend over the last decade.

Diagram 2: South American Crude Oils with an emphasis on the Liza Crude



Liza Data from Exxon's Online Assay Library

Where are the main demand and supply hubs for Crude Oil?

In 2018, total world consumption of crude oil stood at approximately 100 million bpd, up 13% from 2010 (BP, 2019). The main demand hubs are the US, China, India and Japan, with demand in Middle East rising quickly. The aggregate of North America and Europe continues to lead consumption, but their demand has stagnated due to the efficiency gains achieved. Asia Pacific is the largest individual region and due to its rapid growth it is expected in the coming decade to surpass the demand from North America and Europe.

The US consumes more light distillates than Europe while the latter consumes more middle distillates. The difference in consumption is due to the gasoline-based demand for the US transport sector, while diesel engines are more common in Europe. In 2018, light distillates accounted for 47% of US consumption and in Europe middle distillates accounted for 55% (BP, 2019). Asia Pacific consumes the most fuel oil per region. China demanded nearly 600,000 bpd in fuel oil for 2018 as compared to 321,000 bpd in US demand. However, China has reduced its reliance on fuel oil from 15% of consumption in 2000 to 4% of consumption in 2018 against an explosion of demand from circa 5 million bpd to 13.5 million bpd over the period. The country is indifferent in the consumption of light and middle distillates, circa 4.4 million bpd for each in 2018.

Out of the circa 100 million bpd crude oil production, the US reigns supreme as the top producer of crude. US production has been greatly spurred by the emergence of shale oil, 2007 production was at 7 million bpd versus 2018 production, greater than 15 million bpd (BP, 2019). Aside from US production, Saudi Arabia and Russia, and generally non-OECD countries dominate. The non-OECD countries control 3/4 of world output.

A large amount of US demand is met domestically. China, India and Japan rely heavily on trade. The 2018 global trade in crude oil was circa 46 million bpd in 2018 with China, India and Japan accounting for 36% of imports (OPEC, 2019). The US is nevertheless the second-largest importer of crude. Asia Pacific accounts for greater than 50% of OPEC's exports. The European import demand for crude is largely serviced by Russia but due to geo-political and economic reasons, Russia is seeking to focus more on the Asian market. The top exporters are Saudi Arabia, Russia and Iraq. OPEC (54%) and the Russia (11%) accounts for roughly 65% of the export market.

Box 1: Crude Quality and Refinery Demand

Many US refineries have made a substantial investment in the capability to extract more marketable cuts from lower quality crude. Complex US refineries are configured for heavier crude than the circa 40 API and above light shale produced domestically. According to the EIA (2019a), 58% of US imported crude is accounted by heavy crude oil with a less than 25 API. Canada dominates the heavy crude oil imports with its robust infrastructure of pipelines to the US. The US's Midwest and Rocky Mountain refineries are dependent on the heavy crude due in part to logistical reasons. However, the US refinery's crude slate has started to reflect the new reality of surging light sweet production; per the EIA (2019a), the bulk of the US refinery capacity is located in the Gulf Coast where the average 30 API crude in 2011 intake is 32.6 API in 2018, a gradual march to lighter crudes. Refineries in Asia have geared their intake to light and medium sour Middle Eastern crude. Japan is heavily reliant on light and medium sour crude at 70% of feedstock along with sizeable demand from China and India (IEA, 2019b). Refineries generally possess the ability to switch their crude slate where feasible. Capital investment made in equipment to transform the heavier hydrocarbons into lighter products does not rule out a switch to a lighter refinery slate. The capital investment in the conversion units is treated as a sunk cost and based on the technical and economic factors such as the market prices per varying barrel grades versus the cost of the lower utilisation of upgrading units, the light crude may be more attractive.

What are the determinants of Crude Oil Price?

Energy markets are known for their high degree of price variation. The highest price volatility is attributed to the crude oil market, while the refined products of crude oil generally display lower yet significant volatility. Key variables influencing the price of oil include external shocks to the physical availability of crude (flow supply shocks), fluctuations in the global business cycle and the inventory or stock of crude. Flow supply shocks disrupt the volume of oil coming out of the ground. It is often caused by political events in producing countries and exerts an upward pressure on price. A slowdown in the global economy is known for its downward pressure on price due to lower aggregate demand for crude as industry and manufacturing decline. Speculative demand linked to the inventory of oil influences price. If the stock of oil held is persistently low, this suggests that the oil market is becoming tighter and will put an upward pressure on prices. Similarly, if the market does not anticipate a sizeable decline in the inventory of oil, expect an upward price movement. Outside of this, OPEC and Russia exert an influence on price by varying production. Success of this influence depends in part on US production, specifically US shale production. In the short term, where fluctuations are high, price in the crude oil market is heavily influenced by the above factors, while in the long run the price, is guided by market fundamentals.

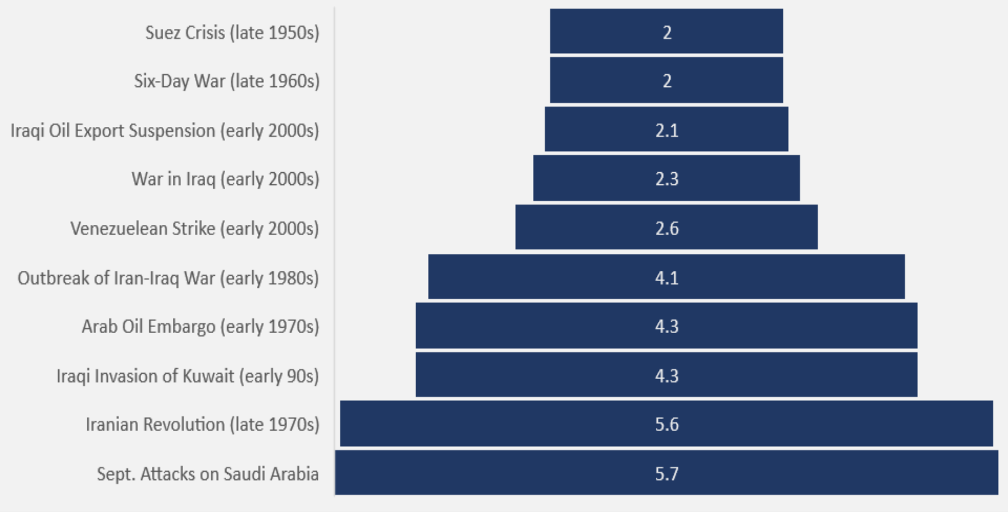
How did we arrive at the current sub $50 crude oil price environment?

From highs of over $100 per barrel in 2014, Brent crude plummeted to its eventual 2014 to 2016 low of sub $30 in January 2016. The market developed momentum and demonstrated an upward trend over 2016, 2017 and most of 2018. The growth in crude prices was a factor of global demand. World GDP demonstrated strong growth from 2016 to 2017, driven by the Asia Pacific region. OPEC, in collaboration with Russia, facilitated the rise by an agreement made at the end of 2016 and enforced until June 2018 to reduce production in an attempt to place a floor on the price. The strategy was impactful but fettered by surging US shale production. Other contributing factors to the price rise were the flow supply issues from geo-political events, such as in Venezuela and Iran, and maintenance caused production outages such as in Russia and the North Sea.

At the start of 2018, crude pierced the $70 per barrel price and the benchmark flipped into backwardation. Backwardation refers to the spot price of crude being priced at a premium to the crude oil futures contracts. It is a sign of tightening supplies and strong demand today and encourages those who have stored physical crude to release it into the market. Research by the Oxford Institute of Energy stated in early 2018 that given the surging US shale oil production, OPEC and Russia would have to keep their production cut agreement for the entire 2018. This did not occur and at the June 2018 meeting, a decision was made to exit the agreement in order to cool prices by increasing production. The decision to increase supply in June 2018, combined with world economic challenges, created the recipe for the drop in October 2018. Global oil demand growth was revised down on the expectations of slower growth in China, India and other emerging economies, trade tensions between the US and China, uncertainty in the UK over Brexit, currency woes in some economies and concern over supply discipline to remedy the crude oil glut. There was a brief rally in Brent price from the OPEC + December 2018 decision to cut production by 1.2 million bpd. However, 2018 ended with a sub $55 Brent price.

The first quarter of 2019 registered a strong rally in price, which continued into the first month of the second quarter. The five-month recovery to the mid-70s in May was fueled in part by evidence of the OPEC + adherence to the agreed production cuts, the negative flow supply ramifications from extended US sanctions in Venezuela and Iran and promising signs for a US-China trade deal with a pause on new tariffs. The gains were substantially erased by the beginning of August 2019. Despite the OPEC + July decision to extend the 1.2 million bpd production cuts to March 2020, the price collapsed on the strain from the oversupplied state of the crude market caused by relentless US oil production and a weaker demand outlook. The top two price lows outside of January, circa $57, occurred in August and October. An escalation in the US-China trade war impacted the August market. Both countries announced new tariffs impacting billions in trade. US-Iran tensions flared following scattered attacks in the Strait of Hormuz, the most important chokepoint of oil where 21 million bpd traversed in 2018 (EIA, 2019b), and on the Saudi- oil infrastructure over the May to September period. These attacks briefly supported price with the most significant attack in September 2019, impacting over 5 million bpd and resulting in a spike close to $70 against a sub $60 month start (FT, 2019b). The announcement of a Brexit deal, an agreement in principle on a US-China trade deal, and deeper production cuts, 2.1 million bpd on aggregate, from the December OPEC + meeting underscored the positive trend in the final quarter of 2019.

Diagram 3: Major Supply Outages (million bpd)



In January 2020, Brent price registered a daily high over the $70 mark for the first time since September 2019. The gain was caused by the US's assassination of a senior commander in the Iranian Revolutionary Guard, an entity the country labelled as a Foreign Terrorist Organisation. The heightened expectation of a supply shock from the Middle East region deescalated after Iran's retaliation avoided casualties and the US decided against a response. Market attention shifted to the slowing global demand against the abundant supply and the impact of the novel coronavirus (COVID-19) outbreak.

Analysts closely monitored the spread of the virus to ascertain the depth of its impact on the Chinese economy and the extent of its global reach; some based their expectation on the 2003 SARS's outbreak. A model from Goldman Sachs suggested a mere $3 per barrel price fall (FT, 2020c). Market concern over a deeper ramification of COVID-19 on crude oil market and the pre-existing state of oversupply led to reports that OPEC + was considering deeper production cuts, as price dipped to a January 2020 close of sub $60. The structure of the forward curve shifted to contango for the first time since July 2019 in February. The IEA (2020c) trimmed its growth forecasts of 2020 crude demand by 30% to 825,000 bpd and revised its expectation of the first quarter to a contraction. The assessment in its February monthly report disclosed the deeper economic implications of COVID-19 to the 2003 SARS epidemic on China due in part to the country's elevated importance to the world economy.

The March 2020 market reflects the pandemic status of the virus and the OPEC + fallout. Commerce and trade in major economies such as China, the US, Canada and the UK took a back seat to the necessary restriction in movement. Instead of OPEC and its allies arriving at an agreement over deeper production cuts in the attempt to place a price floor, a rift emerged between Saudi Arabia and Russia. The reasoning behind Russia's decision to not support further production cuts can be debated with arguments such as a strategic move for market share and an attack on US shale production. However, the outcome of the breakdown in cooperation has been an even greater overabundance of crude oil. Saudi Arabia intends to ramp up production to respond to Russia's rejection of the deal and offer deep discounts against its reference price to gain market share against the country. The Brent price is currently below $35 at the time of writing and has dipped into the 20s.

Table 2: A Breakdown of Major Events impacting Crude Oil Price in 2019[3]

Brent Crude 2019	*Price Influences*
January	S (+) Expectations of supply discipline from the December OPEC + production cut decision S (+) Risk of further conflict in Libya from an aggressive attempt to regain control of El Sharara, the country's largest oil field S (+) Expanded US sanctions on Venezuela and deteriorating production D (+) Expectations of an early US-China trade deal and a delay to new tariffs
February	S (-) Expectations of an increase to Libya's output from success in regaining control over the El Sharara oil field S (-) US President's comments on oil prices being too high and warning to OPEC to avoid risking global growth from production cuts that trigger a higher oil price D (- & +) Concern over the lack of progress on the US-China trade deal, followed by renewed optimism over the indication that the deal deadline will be adjusted and a pause placed on tariffs that were likely in the March no deal scenario. D (+) A decline of US inventories in excess of analysts' expectation for the week ending February 22nd
March	S (-) EIA confirms raging US oil production, growing at the fastest observed pace, surpassing the 2014 high S (+) Declining production in sanction hit Venezuela, IEA warns of greater decline S (+) Public unrest in Alegria over the need for political reform and the enhanced likelihood of a possible supply shock D (-) Poor European manufacturing data and lack of US-China trade deal D (-) Lower than expected drawdown on US inventories, week ending March 15th

[3] Expectation plays a key role in crude oil pricing due to the role of the futures market in price setting. A separate publication will examine crude oil futures. However, it must be noted that many transactions in the crude oil market are paper based due to involvement of hedgers and speculators, and often do not result in the physical delivery of crude oil. The Brent price popularly quoted refers to the Front Month (the futures contract with the closest expiration date).

April	S (+) Expectations that OPEC + will extend its production cuts S (+) US removal of waivers to major countries that import from the sanction hit Iran S (+) Continued production slide for sanction hit Venezuela S (+) Production risk from continued civil unrest in Alegria D (+) Strong economic data on US and China, boosting global growth outlook D (-) Unexpected buildup of US crude inventories
May	S (-) Increasing US and Russia production S (+) Attack on Saudi Arabia's oil infrastructure, followed by attacks on four oil tankers off the coast of Fujairah, UAE, in close proximity to the Strait of Hormuz chokepoint. Attacks claimed by Yemini Houthi rebels, a known conduit of Iran. S (+) Saudi Arabia's Energy Minister stating that OPEC + has a consensus on extending production cuts D (-) The largest level of US crude inventories since 2018 and concern over global economic growth
June	S (+) Two oil tankers attacked in the Strait of Hormuz chokepoint with the US promptly blaming Iran S (+) US-Iran tensions flare as US surveillance drone shot down by Iran. Conflicting reports from the two countries whether the drone was over international airspace in the Strait of Hormuz. Market expectations of a US retaliation S (-) IEA's comments on 2020 in its June Monthly Oil Report highlights the diminished impact of production cuts on the current supply glut due to surging US production and the expected increase from other non-OPEC + production S (+) Informal agreement by Saudi Arabia and Russia before the July OPEC + meeting to continue production cuts D (-) Unexpected increase in US inventories after analysts forecast a decline for the week ending June 14th. D (-) Slower than expected growth in China, dampening the global economic outlook
July	S (+ & -) OPEC + production cuts officially extended to March 31st, 2020. While the suggested impact is positive, prices declined following the announcement due to the positive impact from expectations of the news being built into the price in the lead-up. The decline further

	demonstrates concern over weakening demand and the continuing supply surplus
	S (-) Signs of de-escalation in Middle East tensions on the US-Iran front. US Secretary of State indicated Iran's willingness to discuss their nuclear weapons programme, the root of the tension.
	S (+) The Iranian Revolutionary Guard seized a British-flag oil tanker in the Strait of Hormuz after the UK's seizure of an Iranian oil tanker on the grounds that it was suspected of violating EU sanctions against Syria
	D (+) Significantly larger drawdowns from the US inventories than forecasted, week ending June 28th, July 5th and July 26th
August	S (+) Further deterioration in Venezuela's production expected with the US expanding sanctions over Venezuela, freezing government assets in the US and preventing transactions with Venezuelan Authorities
	D (-) Lack of progress on US-China trade deal led to the US announcing plans for a 10% tariff on billions of additional Chinese goods, excluding the $250 billion subject to a 25% tariff. China responded by announcing the planned enforcement of a new tariff on US imports. The global demand outlook diminished following these announcements
	D (-) Increase in US inventories
September	S (+) First statement of Saudi Arabia's new Energy Minister, expressing commitment to support price via production cuts
	S (+) Attacks on Saudi Arabia's oil facilities, impacting 5 million bpd or circa 5% of world supply. The US blamed the Houthi rebels, aligned to Iran
	D (+) Stronger than expected economic data on China
	D (+) Improved outlook on US-China trade deal from the US administration's removal of their National Security Advisor, John Bolton, due to several disagreements such as on the US-China trade talks
October	D (-) IEA and OPEC, among others, trimmed their demand outlook
	D (-) Poor data on China's economic performance. US-China trade war continues
	D (-) IMF negatively revised its economic growth projections for the Gulf States
	D (-) Larger than expected increase to US inventories

	D (+) The UK and EU announcement of a Brexit deal
November	S (+) UK's moratorium on fracking and the possibility of a policy shift on shale production from the 2020 US elections
	S (+) Uncertainty over the December meeting of OPEC + to continue and consider deeper cuts
	D (+) US Trade Representative indicates progress on US-China trade deal
December	D (+) Improved global economic outlook from news that the US and China have unofficially agreed on the terms of a trade deal, averting concern over the expected implementation of additional tariffs, circa $160 billion on China's consumer goods, in mid-December.
	S (+) Increasing expectations of an appropriate OPEC + address to the supply glut. This was followed by an official decision for an additional 500,000 bpd cut to the existing 1.2 million bpd reduction. Saudi Arabia pledged to a further 400,000 bpd cut above their quota, resulting in a total output reduction from OPEC + of 2.1 million bpd until late March 2020.

Short Term Outlook

The pre-March assessments of COVID-19's risk to the global economy and the crude oil market were largely aligned to the 2003 SARS epidemic. The global crisis that would emerge as economies ground to a near pause was not accounted for by most analysts. The focus on China for the implications on the crude oil market is evidenced from the height of $60 on February 20th, triggered by China reporting its lowest daily number of new coronavirus cases and announcements on the planned economic stimulus for China.

IEA's (2020b) January demand forecast suggests an increase from an expected 100.1 million bpd first quarter (Q1) to 100.9 million bpd in the second quarter (Q2), followed by a 1.2 million barrel bpd gain to 102.1 million bpd in the third quarter (Q3). The revision in its February 13th forecast suggests a lower Q1 and Q2 per the January forecast but foresees the 100.6 million bpd Q2 demand growing at a faster pace to 102.3 million bpd in Q3 (IEA, 2020c). While the forecasted total demand for 2020 was reduced in February from 101.5 million bpd to 101.1 million bpd it remained above the 100.1 million bpd registered in 2019.

The IEA's March report (2020d) highlights the shift in the assessment to a global crisis and announced the expectation that the total demand for oil will contract in 2020 with reduced demand from China and the OECD countries. The further deterioration of the crude oil market is evidenced in the late March IHS Markit (2020) estimates that up to 15 million bpd in global demand could be temporarily erased over a four to eight week horizon and in the absence of a production cut deal, oil inventories could triple the size of the 2014 to 2016 price collapse highs. The company notes that sustained production at the current level to the end of the second quarter of 2020 will result in a lack of global oil storage. The estimated first half 2020 supply surplus is 1.8 billion barrels against 1.6 billion barrels of available crude oil storage.

A lack of storage capacity would further depress crude oil prices in 2020, ceteris paribus. The price quotes of the international benchmarks are based on the respective front month. Given the current contango structure of the market (the higher price for crude deliveries in the future versus deliveries today), integrated oil companies and commodity trading houses will, to their best ability, store crude oil to sell forward at a higher price. However, the lack of an attractive spot trade and the absence of storage availability will significantly depress the front month price since market participants will attempt to distance themselves from physical deliveries.[4]

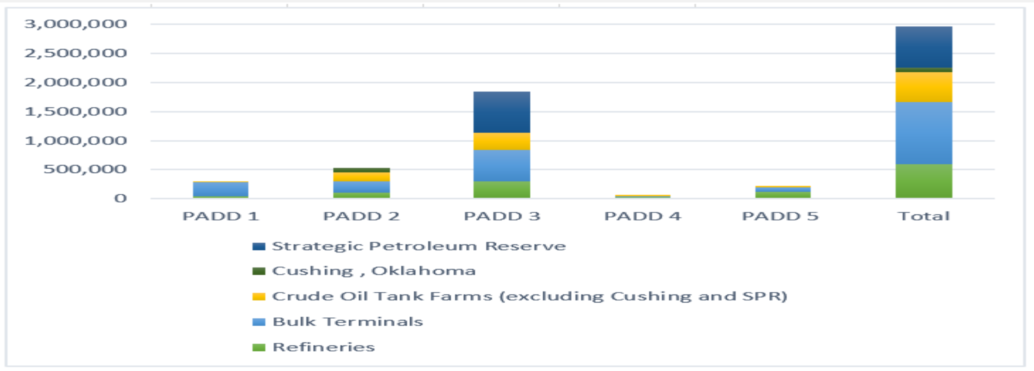
Box 2: Oil Storage Capacity

The midstream sector has come under scrutiny, specifically the world's storage capacity against the slumping oil price. Storage facilities for petroleum and

[4] The WTI benchmark would be particularly vulnerable due its pipeline nature. The Brent benchmark, an offshore crude basket, is less bound by infrastructural and logistical restrictions, and will be easier to ship to existing storage as the working capacity tightens to zero.

petroleum products are owned by integrated oil companies, commodity trading houses and independent storage companies, among others. While refiners store due to the need for production management and to smooth any potential disruption in the supply chain, commodity traders are eagled eyed on arbitrage and price differential opportunities. Trading companies possess significant storage capacity to ensure operational flexibility, the basic requirement for a contango play. Vitol is the largest independent oil trader and it possesses 9.5 million cbm of storage capacity, spanning fourteen countries (VTTI, 2020). Global tank storage capacity per Insights Global (2020) is at circa 1 billion cbm. Europe is estimated to have 235 million cbm followed by the 207 million cbm in North America and 93.3 million cbm in the Middle East. Three high ranking locations per storage capacity are Rotterdam (The Netherlands), Jurong Island (Singapore) and Fujairah (United Arab Emirates). Oil (crude and products) storage in the US is viewed through the five Petroleum Administration for Defense Districts (PADD). EIA (2019c) data reflects a working storage capacity of circa 3 billion barrels. The top two working capacity regions are PADD 3 (the Gulf Coast), home of the strategic petroleum reserve, and PADD 2 (the Midwest), which contains Cushing, Oklahoma. In assessing available storage capacity to domestic production, IHS Markit (2020) has ranked Nigeria and Brazil at the low end of the range with less than 2 days of storage, Russia in the middle at 8 days of storage and 18 days of storage to Saudi Arabia at the upper end. The US can store 30.2 days of production.

Diagram 4: Working Storage Capacity estimates for the US



Data Source: EIA (2019c)

The Takeaway

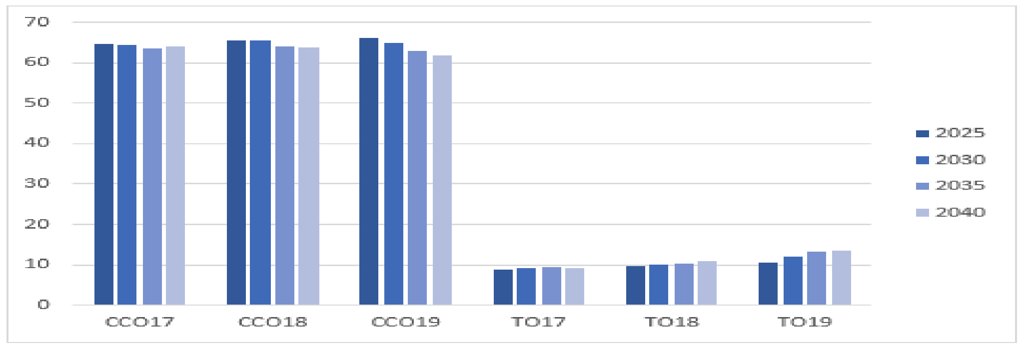
The crude oil market is experiencing an unprecedented surplus. Global demand has collapsed due to the coronavirus shock. However, concern over the global economy predates the coronavirus pandemic due to the US-China trade war and the uncertainty caused over Brexit. Against the demand worries, US shale oil production surged, forcing OPEC and its partners, such as Russia, to step in with the necessary production cuts. US oil production in 2019 grew at the fastest observed pace, surpassing its 2014 high. At year-end 2019, OPEC + announced deeper production cuts to rebalance the market and place a floor on price.

An OPEC + led production adjustment to the current price collapse has not occurred. Talks between the two key parties, Saudi Arabia and Russia have deteriorated into an oil price war. US shale and other production outside of the low-cost region of the global supply curve will suffer in the current price environment. The competition for market share, new non-OPEC + production increases such as Guyana and the worsening global macroeconomic environment have led to questions over the world's storage capacity for crude as the immediate outlook for price remains grim on the back of gushing supply.

The Forecasting Disclaimer

The oil and gas sector has attracted a disproportionate number of forecasts compared to other commodities due to its importance in micro and macro decision making. Forecasts on crude oil price, demand and supply can be found from the International Energy Agency, the US's Energy Information Administration, the World Bank, Deutsche Bank and IHS Markit, among others. The two most widely cited and robust (see Moghaddam et. al. 2018) are from the IEA and EIA. Nevertheless, the most robust forecasts rely on necessary assumptions and are based on the state of information at the time of the forecast. Demand, supply and price forecasts are thus subject to revision due to changes in the underlying assumptions. The US shale oil production forecast is a noteworthy example with its significant upward revision due to an updated resource base and surging production. Technology improvements can lead to greater recovery of post peak shale production and further enhance future shale oil estimates.

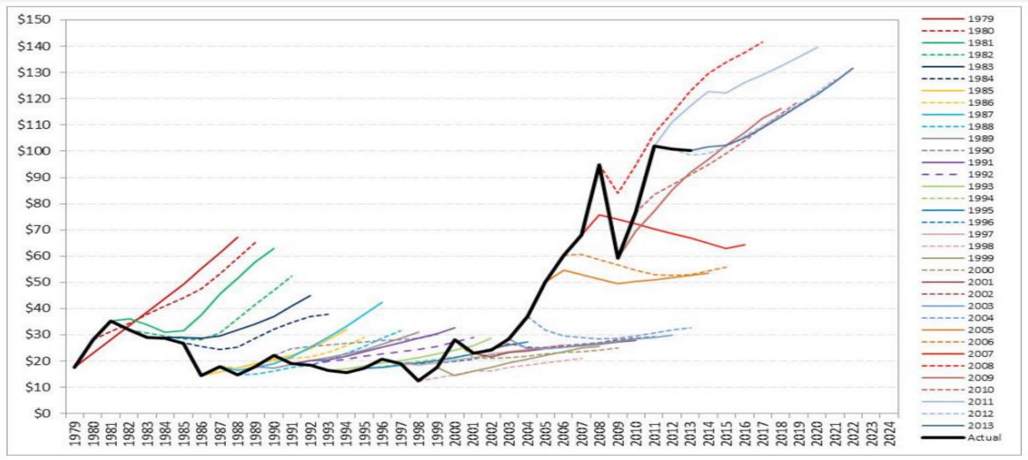
Diagram 5: IEA's forecasts from 2017 to 2019 on Conventional Crude Oil and US Tight Oil.



Data Source: WEO 2017, 2018 and 2019

The spread between year to year price forecasts can be observed in Medlock's (2013) graphical depiction of the EIA's 10-year oil forecasts from 1979 to 2013. The variation from forecasts is large in the 1980s and the 2000s, while there is a convergence in the forecasts of the 1990s to a circa $30 price level.

Extract 1: EIA's 10-year oil forecasts from 1979 to 2013



Medlock (2013)

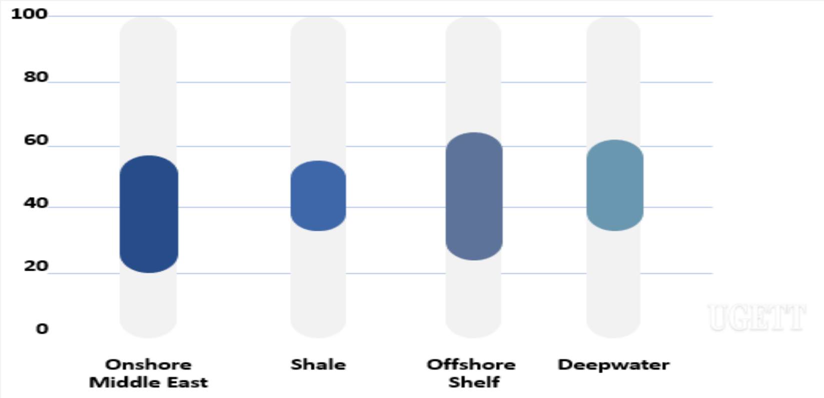
How do IOCs react to a sub $50 price collapse? Emphasis on the offshore sector

The 2020 price collapse represents the second major blow to oil exploration and production projects over the last ten years. Brent crude sustained a sub $50 price for a prolonged period from late 2014 to 2016 and averaged in the $30s for the first two months of 2016. The low-price environment was accompanied by cost-cutting measures. Oil companies purged discretionary spending and pruned operations and planned investments in line with the new price reality. The measures translated to a pause in the final investment decision of new projects and reductions in contractors and workforce size, and renumeration. Only six major upstream projects received their final investment decision in 2015 against an annual average of 30 to 50 upstream projects (PWC, 2015).

The offshore industry is yet to recover to the prime days experienced before the 2014 to 2016 oil price slump. Offshore capital expenditure from 2010 to 2014 averaged just above $150 billion per year but fell to sub $60 billion in 2016 (Clarkson Research, 2020). Growth in capital expenditure was experienced in 2017 against rising oil prices. The strong economics of the Liza Phase 1 development offshore Guyana led to its 2017 FID (Hess, 2019). In late 2018, Clarkson Research suggested that the offshore market had finally bottomed out and there was a change in the stage of the cycle.

During the first price collapse of the last decade most E&P projects had a breakeven cost of over $50 per barrel. Rystad Energy’s 2015 cost of supply curve shows the weighted average breakeven for shale at $68 and deepwater at $62. In recent years, the deepwater and shale production cost curves have considerably declined; shale has a lower breakeven at $46 than deepwater at $58. According to Reuters (2020) breakeven prices for US shale by basin are Scoop/Stack ($48), Bakken ($47), Niobara ($46), Eagle Ford ($46), Midland ($41), Permian ($40) and Delaware ($39). The breakeven costs for deepwater projects range from the $30s to the $60s with Brazil and Guyana at the lower end due to leading pre-FID project economics. Per the 2019 cost of supply curve, onshore Middle East projects have a weighted average breakeven of $42 and the lower end of the cost range is circa $20. It is important to note that breakeven cost calculations for oil projects will vary per the methodology adopted; breakeven costs convey the oil price at which a project is deemed commercial. Rystad Energy calculates these costs on a Brent Equivalent oil price and uses a 10% discount rate to find the price at which the net present value (NPV) of the project is zero.

Diagram 6: Global Supply Cost Curve ($ per barrel Brent Break-even price range)



Data Source: Rystad Energy UCube (2019)

Despite the improvements in breakeven costs, oil companies have begun taking similar action to 2014 due to the current oil price being well below $40. The companies will firstly address the low hanging fruit in their cost-cutting activities before resorting to fundamental changes in cost structure. IOCs will be strategically thinking about their scale and scope of operation. If the company is in a healthy financial position it may be able to take advantage of the depressed asset prices that accompany an oil downturn. Monetary policies aimed at buoying domestic economies will result in attractive financing rates and thus, companies can leverage to grow and expand while divesting underperforming assets. IOCs and smaller oil companies that have a weak balance sheet will suffer from a credit crunch due to the flight to safety and quality from the lower risk tolerance of financial institutions.

The pause to FID of new projects can be gleaned by BP’s 25% planned reduction in capital expenditure for 2020 and Equinor’s abandonment of its controversial deepwater play in Australia’s marine park (FT, 2020b). The erosion of profitability for existing projects is evidenced in EnQuest’s decision to abandon two North Sea fields that were temporarily paused in 2019 for repairs (FT, 2020a). As in 2014, the oil companies will be quick to demand significant cost reductions from oil fields services (OFS) companies. Just over one year from the beginning of the 2014 collapse, Schlumberger had laid off 15% of its workforce. Rystad Energy (2020) estimates over 1 million oilfield service jobs will be lost in 2020’s downturn against a current workforce of 5 million. The majority will be in the higher cost onshore projects, while 230,000 OFS jobs are expected to be removed from offshore.

How does a significantly lower crude price impact an IOC’s project that has received the Final Investment Decision?

Ideally, the oil price is within range of the forecasted prices generated at the time of the final investment decision. The IOC would have simulated future oil prices and accounted for periods of lower price than the prevailing FID environment in keeping with crude oil’s price volatility. However, an IOC may deviate from planned production due to extreme market movements. The exact project finance implications will depend on the petroleum fiscal regime adopted by the host government. A simplified example is used below for illustrative reasons.

Consider a newly sanctioned oil project under a Production Sharing Agreement where the IOC has agreed to pay a royalty (an amount taken from gross revenues), government profit share (an amount taken from total profit oil) and corporate tax (from its profit share). Total government receipt from the project will flow from three channels, the profit share, the royalty and the taxation.

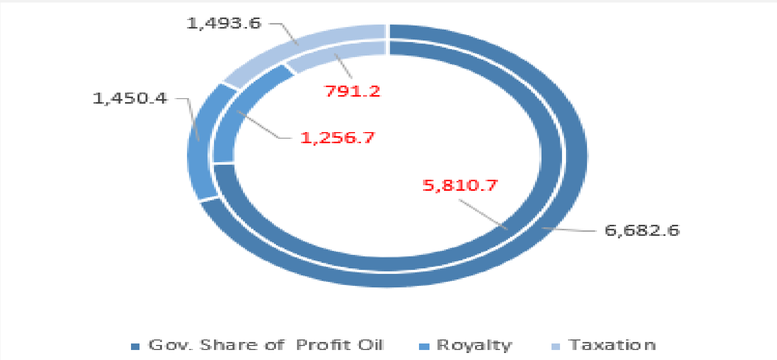
Total Profit Oil, the amount divided into government share and IOC share, is the gross revenue less the sum of the royalty and the cost recovery. The cost recovery is the aggregate of the operating expenditure (OPEX), depreciation and any cost recovery carried forward. PSAs generally provide for cost recovery per period to a maximum percentage of gross revenues; for example, a cost recovery allowed of 50%. If the cost recovery calculated in the period is greater than 50% of gross revenue, the 50% limit is accounted for and the difference constitutes cost recovery carried forward for the next period. The OPEX is found by multiplying the cost of production, also known as lifting cost, per barrel, inflated or deflated per annum, multiplied by the production estimate. The depreciation in the cost recovery calculation arises from the capital expenditure and occurs after year 0 of the project. Given the lag in the start of the project to the year of first oil production, depreciation that accumulates in the years outside of production contributes to cost recovery carried forward. The Taxable Income value is derived from gross revenue less the sum of royalty, depreciation, OPEX, Government Share and taxable loss carried forward.

An oil price collapse from north of $60 to the $30s and prolonged low-price environment assuming a production cost of $20 will firstly trim the gross revenues collected by the IOC and thus, reduce the royalty to the government. The lower gross revenues will feed into a lower ability to recover costs in the early years of the project, generally cost recovery peaks in the first half of the project life. However, PSAs often safeguard IOCs by allowing the excess of the cost recovery cap to be carried forward to the next period and the outcome is a prolonged deduction from profit oil to recover costs over the project life. The lessened total profit results in a smaller pie of profit oil to slice between the IOC and the host government. The taxation revenue stream of government is also significantly impacted. The thin margin between the oil price and the operating expenditure coupled with the depreciation of the substantial capital expenditure is likely to send taxable income into negative territory and the PSA may allow for these losses to be carried forward and accumulated against future profitability.

Oil projects are known for their capital intensity and high leverage. In a lower than expected oil price environment, the IOC will be faced with reduced cash flows and could encounter debt repayment issues. However, the project finance nature of the investment distances the IOC from the debt held by the project company. The cash flow available for the project's debt service (CADS) is equal to gross revenue inflow less outflows such as royalty, capital expenditure, operating expenditure, government share of profit oil, increases to net working capital, among others. The equity cash flow to the IOC is found after accounting for debt payments. A prolonged low in the oil price close to breakeven will erode the IOC ability to generate sizeable equity cash flows from the project and cause concern over debt repayments while a prolonged oil price below the cost of production or lifting costs will jeopardize the project's production schedule. If the IOC is faced with a supply surplus environment in which the gross revenues generated cannot cover the operating expenses, the company may be forced to suspend production until market conditions improve, pending the ability to store continued output and cost assessments of deviating from planned production.

See Numerical Example in Appendix[5]

Diagram 7: Host Government Project Finance impact from a Prolonged Price Low. Outer circles from an average $60 per barrel over the project life versus the inner circles accounting for a five year low of $35 (million USD)



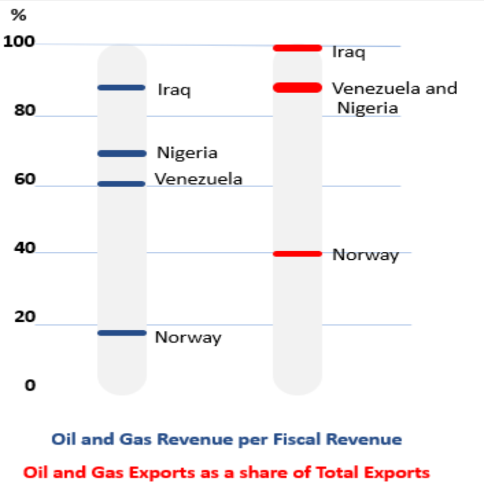
[5] Monte Carlo Simulation or other advanced techniques would be used by an IOC to gauge oil price over the project life. The numerical case is a simplified example that uses several unrealistic assumptions.

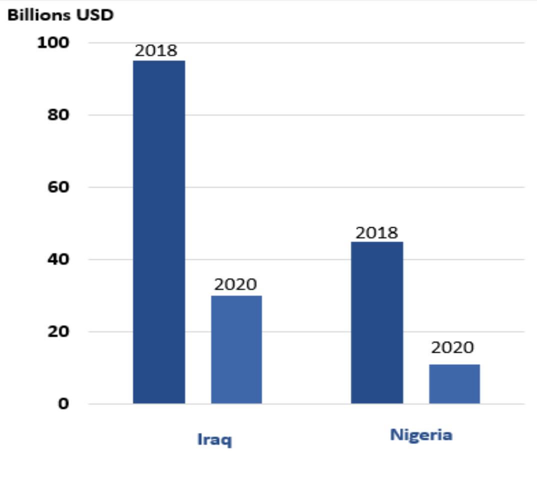
Box 3: Fiscal Breakeven

The fiscal breakeven refers to the minimum oil price that an exporting country requires in order to meet its expected spending and balance the budget. The fiscal breakeven of major producing countries is often a large positive deviation from the oil project's breakeven price. A 2015 analysis by the Financial Times on the ability of OPEC member states to endure a prolonged low-price environment is instructive. The analysis reveals that the best positioned OPEC countries are those with small populations and sovereign wealth funds such as UAE and Kuwait. The UAE at the time had the lowest fiscal breakeven of $61, while Saudi Arabia sat in the middle of the range at $88 (FT, 2019a). OPEC countries such as Libya and Iraq require an oil price greater than $100 for their budget to breakeven. Venezuela and Nigeria are also positioned at the high end of the range. The 2014 oil price collapse triggered a wave of reforms aimed at economic diversification, but the issue of high fiscal breakeven remains. Many of the Gulf Cooperation Council countries, Venezuela and Nigeria exhibited consistent fiscal deficits over the 2014 to 2018 period.

Diagram 8: Oil and Gas Revenue per Fiscal Revenue and Exports as a share of Total Exports in selected countries

Diagram 9: Net Income in Oil Product for 2018 and estimate for 2020





Data Source: IEA (2020a)

How will renewable energy projects be impacted by a prolonged oil price low?

Given Rystad Energy's most recent global supply cost curve, a prolonged oil price below $50 will substantially diminish the attractiveness of most new crude oil projects. Renewable energy investment has traditionally registered a lower return on investment against oil supply projects but will become more attractive in the low-price environment. Oil companies will be strategically thinking about their scope of operations and the low oil price environment can speed up their pace of entrance into the renewable space. According to Wood Mackenzie (2020), most of the pre-FID oil and gas projects at $35 will produce average returns, on an IRR basis, in line with the low risk solar and wind projects.

Investment in Oil Supply and Power

Oil and gas supply investment exceeded power sector investment, which includes fossil fuel and renewable energy generation investment, until 2016. The gap of at least 100 billion per year between oil and gas and the power sector in 2010 and 2011 significantly diverged from 2012 to 2014 as oil and gas breached the $1 trillion mark per year and power sector investment hovered in the $700 billion to $800 billion range (IEA, 2019a). The slash in the 2014 oil price led to a three-year decline in oil and gas supply investment. In 2018, investment in the sector did not decline and remained largely unchanged.

The dominance of power sector investment is primarily attributed to renewable energy. Investment in renewable energy capacity has exceeded fossil fuel generation investment since 2014. Despite the dominance, there has been a decline in the investment amount in recent years. One contributing reason is the cost reductions in renewable energy; the capital cost for solar PV declined by 75% since 2010, onshore wind by 20% and battery storage by 50% (FSFM, 2019). From 2010 to the first half of 2019 it is estimated that $2.6 trillion has flowed to renewable energy capacity investments, with $1.3 trillion to solar. China and the US account for over 1 trillion of the investment in the past decade (FSFM, 2019). Roughly a quarter of investment has been made in Europe. Public markets in 2018 poured $6 billion into renewable energy companies (solar securing $3 billion) and venture capital and private equity invested $2 billion.

Renewable energy investment required special support to progress the sector from its embryonic stage towards maturity. The lower return on investment and risks to investors have inspired a range of public policies across countries such as a fixed feed in tariff, feed in premium, contracts for differences and renewable obligation initiatives. While the compatibility of the policy is subject to market design, it is aimed at creating certainty over cash flows and reducing the cost of capital of renewable energy projects. For example, the fixed feed in tariff measure gives price security by guaranteeing offtaker payments over a specific period, independent of market price, in contrast to the feed in premium, which only gives the renewable energy producer a premium above the market price. The improvements in renewable energy costs and its cost competitiveness against fossil fuel generation have led to questions over continued de-risking. Per the UK's Solar Trade Association (2019), large-scale PV project costs have fallen to an extent where subsidy free projects are possible.

Will a strong recovery of global demand and inadequate investment in Upstream Projects pave the road for price highs?

Adequate investment in existing and new crude oil projects is an indispensable element in future market security and the avoidance of price extremes. Oil field production suffers from a natural rate of decline as the reservoir is depleted over the project life. Companies invest in enhancing field production and thus, the observed post-peak decline rate is less than the natural rate of decline.

According to the IEA (2019b), the global average observed post-peak decline for conventional crude oil is 6.1%. Shale production is known for its faster natural rate of decline and requires greater investment to buoy field declines.

Underinvestment in oil supply projects that results in a mismatch between demand and supply cannot be quickly remedied from a supply perspective due to the complex nature of oil projects and their delayed time to market. Spare capacity from leading producers such as OPEC, may provide relief, but the erosion of such capacity to assist the gap leaves the market crippled and exposed in the face of unexpected events. There has been progress in the time gap between FID and first oil; upstream projects are on average 20% faster at bringing capacity to market than in 2010 (IEA, 2019a). However, there remains at least a 3 to 4 years gap from FID to first oil and this underpins the pressure for a high price extreme in the case of underinvestment.

Upstream oil and gas investment declined due to the 2014 price collapse and sustained low to 2016. The investment level in 2014 surpassed the $800 billion mark and fell by circa $300 billion in 2015 (IEA, 2019a). It further collapsed in the $400 billion territory where it has posted a recovery to 2018 but remains 42% off the 2014 peak at $475 billion. The IEA notes the apparent stark contrast is mitigated by the reduction in upstream cost. The cost-adjusted investment is 16% lower than in 2014. Nevertheless, the IEA's 2017 and 2018 World Energy Outlook warned about a supply crunch risk by the mid-2020s.

Concern is expressed in WEO 2017 over thin investment in conventional projects against growing demand and the formidable task for US tight oil to cover the supply-demand gap if an appropriate scale-up does not materialise. The IEA calculated the 2025 supply-demand gap at 22 million bpd of new upstream projects in WEO 2018, under its New Policy Scenario which accounts for today's policy framework, ambitions, and factors the evolution of known technologies. The needed 16 billion barrels per year of new conventional crude oil stood in contrast to an annual average volume sanctioned over 2014 to 2017 of 8 billion barrels. The likelihood of a supply crunch in 2025 appeared high due to large scale-up required to satisfy growing demand to 2025 and difficulty of the unconventional shale production to cover the gap in the absence of the appropriate scale-up.

The IEA has downgraded the risk in its latest annual report, WEO 2019, on the back of stronger tight oil (shale) statistics and improving upstream oil supply investment. Nevertheless, the risk posed by inadequate investment against a stronger than expected recovery of demand over the coming years cannot be dimisssed and must be closely monitored.

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Appendix

Details	**Assumptions**
Term	*25 Years (Oil Field Project Life)*
Tax Rate	*25%*
Royalty	*5%*
Total Estimated Cost	*$ 4,000 million (Inclusive of Debt and Equity*
Capital Investment	*$1,000 million (Year 0)* *$1,500 million (Year 1)* *$1,000 million (Year 2)* *Debt (60%)* *$400 million (Year 0)* *$1,000 million (Year 1)* *$1,000 million (Year 2)* *Equity (40%)* *$1,600 million (Year 1 to 3)* *Working Capital and Debt Service Reserve Account* *$500 million*
Cost Inflation	*2%*
Cost of Production	*$20 bbl*
Market Price	*$60 bbl*
Depreciation	*15% per annum (Straight Line Basis)*
Cost Recovery Limit	*50%*
Profit Share	*50%*
Annual Production	*25 million bbl (Year 0 to Year 3)* *35 million bbl (Year 4 to Year 9)* *Declining at a rate of 12% (Year 10 to Year 25)*

Year	**Source of Funds**		**Use of Funds**		
	Equity	**Debt**	**Investment**	**Working Cap**	**Cash Reserve**
0	*600*	*4,000*	*1000*	-	-
1	*500*	*1,000*	*1500*	-	-
2	*500*	*1,000*	*1000*	*300*	*200*
Total	***1,600***	***2,400***			

An average $60 per bbl crude oil price over the Project Life

Year	Price of Oil	Production	Gross Revenue	Royalty	Net Revenue	Capital Ex	Dep	Cum Dev	Cost of Production	Opex	Cost Recovery	Cost Recovery C/F
0	60	0	0	0	0	1000	0	0	0	0	0	0
1	60	0	0	0	0	1500	150	150	0	0	0.00	0
2	60	25	1500.00	75.00	1425.00	1000	375	525	20	500.00	750.00	150.00
3	60	25	1500.00	75.00	1425.00	0	525	1050	20.40	510.00	750.00	275.00
4	60	35	2100.00	105.00	1995.00	0	525	1575	20.81	728.28	1050.00	560.00
5	60	35	2100.00	105.00	1995.00	0	525	2100	21.22	742.85	1050.00	763.28
6	60	35	2100.00	105.00	1995.00	0	525	2625	21.65	757.70	1050.00	981.13
7	60	35	2100.00	105.00	1995.00	0	525	3150	22.08	772.86	1050.00	1213.83
8	60	35	2100.00	105.00	1995.00	0	350	3500	22.52	788.31	1050.00	1461.68
9	60	35	2100.00	105.00	1995.00	0	0	0	22.97	804.08	1050.00	1550.00
10	60	30.80	1848.00	92.40	1755.60	0	0	0	23.43	721.74	924.00	1304.08
11	60	27.10	1626.24	81.31	1544.93	0	0	0	23.90	647.84	813.12	1101.82
12	60	23.85	1431.09	71.55	1359.54	0	0	0	24.38	581.50	715.55	936.54
13	60	20.99	1259.36	62.97	1196.39	0	0	0	24.87	521.95	629.68	802.49
14	60	18.47	1108.24	55.41	1052.83	0	0	0	25.36	468.50	468.50	0
15	60	16.25	975.25	48.76	926.49	0	0	0	25.87	420.53	420.53	0
16	60	14.30	858.22	42.91	815.31	0	0	0	26.39	377.47	377.47	0
17	60	12.59	755.23	37.76	717.47	0	0	0	26.92	338.81	338.81	0
18	60	11.08	664.60	33.23	631.37	0	0	0	27.46	304.12	304.12	0
19	60	9.75	584.85	29.24	555.61	0	0	0	28.00	272.98	272.98	0
20	60	8.58	514.67	25.73	488.94	0	0	0	28.56	245.03	245.03	0
21	60	7.55	452.91	22.65	430.26	0	0	0	29.14	219.93	219.93	0
22	60	6.64	398.56	19.93	378.63	0	0	0	29.72	197.41	197.41	0
23	60	5.85	350.73	17.54	333.20	0	0	0	30.31	177.20	175.37	0
24	60	5.14	308.65	15.43	293.21	0	0	0	30.92	159.05	154.32	2
25	60	4.53	271.61	13.58	258.03	0	0	0	31.54	142.77	135.80	7
			29008.21	1450.41	27557.80	3500	3500			11400.91	14192.62	

Total Profit Oil	Gov Share	Company Share	Taxable Loss C/F	Taxable Income	Tax	NWC	Increae in NWC	Cash Reserve For DS	CADS
0	0	0	0	0	0	0	0	0	-1000
0	0	0	0	-150.00	0	0	0	0	-1500
675.00	337.50	337.50	150.00	62.50	15.63	300	300	200	-928
675.00	337.50	337.50	0.00	52.50	13	306	6.00	200	558.38
945.00	472.50	472.50	0.00	269.22	67.31	312.12	6.12	200	720.80
945.00	472.50	472.50	0	254.65	63.66	318.362	6.24	200	709.75
945.00	472.50	472.50	0	239.80	59.95	324.73	6.37	200	698.48
945.00	472.50	472.50	0	224.64	56.16	331.224	6.49	200	686.99
945.00	472.50	472.50	0	384.19	96.05	337.849	6.62	200	631.52
945.00	472.50	472.50	0	718.42	179.61	344.606	6.76	200	532.06
831.60	415.80	415.80	0	618.06	154.51	351.498	6.89	200	456.65
731.81	365.90	365.90	0	531.19	132.80	358.528	7.03	200	391.36
643.99	322.00	322.00	0	456.04	114.01	365.698	7.17	200	334.86
566.71	283.36	283.36	0	391.08	97.77	373.012	7.31	200	286.00
584.32	292.16	292.16	0	292.16	73.04	380.473	7.46	200	211.66
505.96	252.98	252.98	0	252.98	63.24	388.082	7.61	200	182.12
437.84	218.92	218.92	0	218.92	54.73	395.844	7.76	200	156.43
378.66	189.33	189.33	0	189.33	47.33	403.761	7.92	200	134.08
327.25	163.63	163.63	0	163.63	40.91	411.836	8.08	200	114.65
282.63	141.32	141.32	0	141.32	35.33	420.072	8.24	200	97.75
243.91	121.96	121.96	0	121.96	30.49	428.474	8.40	200	83.07
210.33	105.16	105.16	0	105.16	26.29	437.043	8.57	200	70.30
181.22	90.61	90.61	0	90.61	22.65	445.784	8.74	200	59.22
157.83	78.91	78.91	0	77.08	19.27	454.7	8.92	200	48.90
138.89	69.45	69.45	0	64.71	16.18	463.794	9.09	200	39.44
122.22	61.11	61.11	0	54.15	13.54	473.07	9.28	200	504.41
13365.18	6682.59	6682.59			1493.58				4280.73

The impact of a lower average price from Year 2 to Year 6 against the general $60 per barrel average

Year	Price of Oil	Production	Gross Revenue	Royalty	Net Revenue	Capital Ex	Dep	Cum Dev	Cost of Production	Opex	Cost Recovery	Cost Recovery C/F
0	60	0	0	0	0	1000	0	0	0	0	0	0
1	60	0	0	0	0	1500	150	150	0	0	0.00	0
2	35	25	875.00	43.75	831.25	1000	375	525	20	500.00	437.50	150.00
3	35	25	875.00	43.75	831.25	0	525	1050	20.40	510.00	437.50	587.50
4	35	35	1225.00	61.25	1163.75	0	525	1575	20.81	728.28	612.50	1185.00
5	35	35	1225.00	61.25	1163.75	0	525	2100	21.22	742.85	612.50	1825.78
6	35	35	1225.00	61.25	1163.75	0	525	2625	21.65	757.70	612.50	2481.13
7	60	35	2100.00	105.00	1995.00	0	525	3150	22.08	772.86	1050.00	3151.33
8	60	35	2100.00	105.00	1995.00	0	350	3500	22.52	788.31	1050.00	3399.18
9	60	35	2100.00	105.00	1995.00	0	0	0	22.97	804.08	1050.00	3487.50
10	60	30.80	1848.00	92.40	1755.60	0	0	0	23.43	721.74	924.00	3241.58
11	60	27.10	1626.24	81.31	1544.93	0	0	0	23.90	647.84	813.12	3039.32
12	60	23.85	1431.09	71.55	1359.54	0	0	0	24.38	581.50	715.55	2874.04
13	60	20.99	1259.36	62.97	1196.39	0	0	0	24.87	521.95	629.68	2739.99
14	60	18.47	1108.24	55.41	1052.83	0	0	0	25.36	468.50	468.50	0
15	60	16.25	975.25	48.76	926.49	0	0	0	25.87	420.53	420.53	0
16	60	14.30	858.22	42.91	815.31	0	0	0	26.39	377.47	377.47	0
17	60	12.59	755.23	37.76	717.47	0	0	0	26.92	338.81	338.81	0
18	60	11.08	664.60	33.23	631.37	0	0	0	27.46	304.12	304.12	0
19	60	9.75	584.85	29.24	555.61	0	0	0	28.00	272.98	272.98	0
20	60	8.58	514.67	25.73	488.94	0	0	0	28.56	245.03	245.03	0
21	60	7.55	452.91	22.65	430.26	0	0	0	29.14	219.93	219.93	0
22	60	6.64	398.56	19.93	378.63	0	0	0	29.72	197.41	197.41	0
23	60	5.85	350.73	17.54	333.20	0	0	0	30.31	177.20	175.37	0
24	60	5.14	308.65	15.43	293.21	0	0	0	30.92	159.05	154.32	2
25	60	4.53	271.61	13.58	258.03	0	0	0	31.54	142.77	135.80	7
Total			25133.21	1256.66	23876.55	3500	3500			11400.91	12255.12	

Total Profit Oil	Gov Share	Company Share	Taxable Loss C/F	Taxable Income	Tax	NWC	Increae in NWC	Cash Reserve For DS	CADS
0	0	0	0	0	0	0	0	0	-1000
0	0	0	0	-150.00	0	0	0	0	-1500
393.75	196.88	196.88	150.00	-390.63	0	300	300	200	-1366
393.75	196.88	196.88	390.63	-791.25	0	306	6.00	200	118.38
551.25	275.63	275.63	791.25	-1156.41	0	312.12	6.12	200	153.73
551.25	275.63	275.63	1156	-1536.13	0	318.362	6.24	200	139.04
551.25	275.63	275.63	1536	-1930.70	0	324.73	6.37	200	124.06
945.00	472.50	472.50	1931	-1706.06	0	331.224	6.49	200	743.15
945.00	472.50	472.50	1706	-1321.87	0	337.849	6.62	200	727.56
945.00	472.50	472.50	1322	-603.45	0	344.606	6.76	200	711.66
831.60	415.80	415.80	603	14.60	3.65	351.498	6.89	200	607.51
731.81	365.90	365.90	0	531.19	132.80	358.528	7.03	200	391.36
643.99	322.00	322.00	0	456.04	114.01	365.698	7.17	200	334.86
566.71	283.36	283.36	0	391.08	97.77	373.012	7.31	200	286.00
584.32	292.16	292.16	0	292.16	73.04	380.473	7.46	200	211.66
505.96	252.98	252.98	0	252.98	63.24	388.082	7.61	200	182.12
437.84	218.92	218.92	0	218.92	54.73	395.844	7.76	200	156.43
378.66	189.33	189.33	0	189.33	47.33	403.761	7.92	200	134.08
327.25	163.63	163.63	0	163.63	40.91	411.836	8.08	200	114.65
282.63	141.32	141.32	0	141.32	35.33	420.072	8.24	200	97.75
243.91	121.96	121.96	0	121.96	30.49	428.474	8.40	200	83.07
210.33	105.16	105.16	0	105.16	26.29	437.043	8.57	200	70.30
181.22	90.61	90.61	0	90.61	22.65	445.784	8.74	200	59.22
157.83	78.91	78.91	0	77.08	19.27	454.7	8.92	200	48.90
138.89	69.45	69.45	0	64.71	16.18	463.794	9.09	200	39.44
122.22	61.11	61.11	0	54.15	13.54	473.07	9.28	200	504.41
11621.43	5810.71	5810.71			791.23				2173.70

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